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Cutting Electricity Costs for Industrial Plants in a Real-Time World

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AS U.S. ELECTRICITY MARKETS BECOME increasingly competitive, large industrial customers will discover many new choices. These choices include the opportunity to modify the amount and timing of electricity use in response to prices that vary from hour to hour. In addition, customers can sell certain electricity services, including operating reserves and load following, to the system operator. And industrial customers with cogeneration facilities can participate fully in bulk power markets, buying and selling energy and ancillary services in response to changes in spot prices.

The choices will mean real dollars. Using detailed data on one industrial plant's electricity use, cogeneration output and purchases from its local utility, we quantified the benefits of the options listed above. We have concluded that real-time electricity prices will greatly expand the options that industrial customers have for managing their electricity bills.

Of course, large industrial customers have always had some choice in managing electricity costs. Such customers can purchase, under current cost-of-service tariffs, either firm or nonfirm power. If they buy nonfirm power, their rate is lower, typically with a much lower capacity charge. In return for this lower rate, the utility has the right to interrupt the flow of power to the customer. In addition, many utilities offer their large customers time-of-day prices. These prices change on a fixed schedule from hour to hour, but do not depend on current system conditions and costs.

But nonfirm and time-of-day prices are crude simplifications of what is possible with real-time pricing. With real-time pricing, the customer can make time-of-use decisions concerning the amount of electricity to consume (Schweppe et al. 1998). For example, if the price is high but the customer faces tight production deadlines, it might decide to pay the higher price and consume electricity as it otherwise would have. In many cases, customers may invest in equipment that allows them to shift production, and therefore electricity consumption, from one time to another. Real-time pricing allows customers to respond - as they choose - to actual, not expected, power-system conditions.

New technologies may enhance the ability of customers to conveniently, even automatically, adjust their loads to changing electricity prices. For example, The Southern Co. and Honeywell developed software that allows facilities on real-time pricing to automatically change electricity use in response to hourly price signals (Energy 1997).

In response to FERC's Order 888, industry players throughout the country are developing proposals to create independent system operators. These proposals would create markets for certain ancillary services (Hirst et al. 1996). As proposed in California, (Pacific Gas 1997) customers and suppliers can bid into some of these markets.

Industrial Facility Characteristics

The industrial plant we studied has two primary operations: mining and chemical processing. Together, these operations have a peak electrical demand of more than 90 megawatts. The load factor for this industrial facility is about 84 percent, compared with less than 60 percent for U.S. utility systems in general.

Mining involves large equipment that accounts for about half the electricity demand at this facility. In addition to extracting ore from the earth, the facility also processes the ore into end products.

The plant-specific chemical conversion is an exothermic (heat producing) reaction. The heat from this reaction is used to create steam in a boiler. Whatever steam is not needed for other chemical processes is run through a turbine-generator set to produce electricity. Priority in steam use is given to the industrial processes themselves. This particular chemical process currently operates at essentially one speed and therefore produces steam at a near-constant rate. There is little strategic management of the timing and amount of the cogeneration facility's electricity production.

Overall, this cogeneration facility produces more than 40 percent of the plant's electricity consumption. The plant buys electricity from its local utility under a tariff that offers substantial pricing differences between peak and offpeak periods. In particular, the demand charge is 14 times higher during peak (12 hours each weekday) than offpeak hours. The plant shuts down some of its equipment during peak hours to reduce its electric bill, but it does not modify the electrical output of its cogenerator for this purpose.

Figure 1 shows 15-minute data on total electricity consumption, cogenerator electricity output and purchased power for this facility for a full week in April 1997. The mean values of electricity consumption, cogenerator output and purchased power were 80, 34 and 46 MW, respectively. The maximum values were 95, 40 and 74 MW. This graph shows considerable volatility in purchased power, a consequence of the way that the cogeneration facility is operated.

Optimizing Cogenerator Use

We analyzed alternative uses of the cogenerator if this plant faced hourly spot prices. We obtained spot prices for the Pennsylvania-New Jersey-Maryland Interconnection. The PJM spot prices on Aug. 3, 1997 ranged from $10/MWh to $51/MWh, with an average of $27/MWh (see Figure 2).

Faced with electricity prices that varied from hour to hour (rather than prices that were invariant throughout the day), the firm might operate its cogeneration facility differently. We optimized the operation of the cogeneration facility to minimize its daily electric bill. We constrained the optimization by the assumed need to maintain the same 24-hour output from the cogenerator for process purposes. We also imposed different minimum and maximum constraints on the cogenerator's hourly output.

The results show that, depending on the range of output possible from this cogenerator, the facility can cut electricity costs by 12 to 25 percent (see Table 1). As shown in Figure 3, the optimized cogenerator output peaks - and, correspondingly, purchases - are at their lowest level in the late morning and afternoon. Prices are at the highest (above $30/MWh) between 11 a.m. and 6 p.m. that day.

We ran the same cases shown in Table 1 against the PJM prices for Aug. 1 (see Table 2).

Because prices were much less volatile on the 1st than on the 3rd, the relative benefits of optimizing cogenerator production were correspondingly reduced by 25 percent to 35 percent from the values shown in Table 1.

Selling Ancillary Services

In principle, the cogenerator could be run to offset the need to buy certain ancillary services, including regulation, load following and operating reserves. We computed the hourly cost of the load-following service, assuming that its average charge is $10 per MW of capacity and that its price varies from hour to hour with energy prices. We calculated the load-following requirement for each hour as the difference between the average load for that hour and for the previous hour. If the customer's hour-to-hour load changes move in the same direction as spot prices (used here as a proxy for movements in system load), the customer must pay for load following. On the other hand, if the customer's load changes move counter to spot-price changes, the customer receives a credit for load following because its load changes reduce system requirements for load following.

The right hand column of Table 1 shows the optimization results when both energy and load-following costs are considered. Clearly the savings are dominated by reductions in direct electricity costs. Just as clearly, savings increase by considering other services (load following in this case). In this example, optimizing for price changes and load-following costs increases the economic benefit by only 2 to 3 percent. In these cases, the load-following benefit comes primarily at the expense of the energy-cost savings.

The benefits of optimizing for both energy and load-following costs are much greater for the Aug. 1 spot prices (see Table 2). In this case, the dollar savings increase by roughly 75 percent by including load-following costs in optimization of cogenerator output. Whether it is cost-effective to increase the volatility of the cogenerator's electricity output to eliminate the volatility in the purchased-power component would require analysis of the facility's cogenerator operations and costs as well as the utility's rate structure.

In addition to responding to real-time prices and reducing its load-following costs, this facility could sell operating reserves to the system operator. Such sales would grant the system operator the right to a certain megawatt-level of purchased-power demand reduction or cogenerator-output increase within 10 minutes of notification. The system operator could call on these reserves in case of a major system generator or transmission outage. In deciding whether to sell such reserves, the industrial plant would need to assess the risks that these reserves would be called upon against the steady stream of income associated with the sale of what is essentially a call option. In addition, the sale of operating reserves reduces the plant's flexibility to respond to real-time price changes. Thus, the tradeoffs among the facility's response to real-time pricing and the sale of various ancillary services can prove complicated.

These simple and incomplete examples suggest ways that large industrial customers can better manage their electricity use to reduce their costs by:

Modifying the timing of electricity use, which will be increasingly important as real-time pricing becomes widely available;

Modifying the timing of cogenerator-electricity production, which will be increasingly important as real-time pricing becomes widely available;

Controlling the industrial process to reduce the ancillary-services burdens that the industrial plant imposes on the local utility; and

Selling certain ancillary services to the local utility.

Such analyses require a comprehensive consideration of electricity costs and rate tariffs, plant process and production costs, and the possible capital costs associated with increased flexibility in cogeneration-production and electricity-consumption operations. F

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